something firms routinely do all the time. Sometimes referred to as the "make or buy" decision, this is not an exotic choice that could easily be overlooked. Nor is the decision whether to generate power or to purchase from another firm a purely hypothetical option that has little applicability to the electric utility industry in general, or the Southeastern United States in particular. SCE&G is fully aware of the fact that some generating plants in the Carolinas are currently being operated as "merchant plants" selling their electrical output to the wholesale buyers. At the very least, the Company should have investigated whether any of these firms would be interested in negotiating the sale of portions of their output to SCE&G. Similarly, there are numerous merchant generators in the PJM market that might be willing and able to sell firm power to SCE&G.

Admittedly, purchases of firm blocks of power from merchant plants might have a higher expected cost than adding more fossil fuel plants. However, the expected cost is not the only factor to consider, as discussed earlier. A purchase power strategy might be preferable from a retail customer perspective, because wholesale transactions would offer more flexibility and less of the "portfolio" risks alluded to earlier. With wholesale transactions, the Company would not be locked into a multi-decade commitment to a specific type of fuel, or a specific heat rate. If it were to instead enter into shorter term contracts, it would have the flexibility to scale back its use of natural gas over time, or to change suppliers over time, moving to newer plants in the "out" years, if they have a better heat rate.

This added flexibility would provide benefits that are somewhat like the benefits of a "CD ladder." Instead of buying a 20 or 30 year bond, an investor may instead buy multiple CDs with staggered maturity dates. This strategy offers greater flexibility, enabling the investor to "cash out" some of the CDs, in order to change their portfolio if this is warranted by changing circumstances.

To be clear, wholesale power purchases won't eliminate the risks associated with fossil fuels, since most sellers will insist on a floating price that is linked to the unit's actual fuel costs, or to a standardized measure of fuel costs, like the Henry Hub index of natural gas prices. Nevertheless, power purchases do offer some additional flexibility, which translates into the potential for reducing the fuel-related risks shouldered by retail ratepayers. Purchased power offers some a higher degree of flexibility, which can potentially enable the purchaser to minimize some of the risks of over reliance on fossil fuels. For instance, rather than being committed to burning natural gas for 20+ years, the Company can focus on PPAs with a duration of 10 years or less – providing the opportunity to switch to a different energy source if gas prices escalate more than expected.

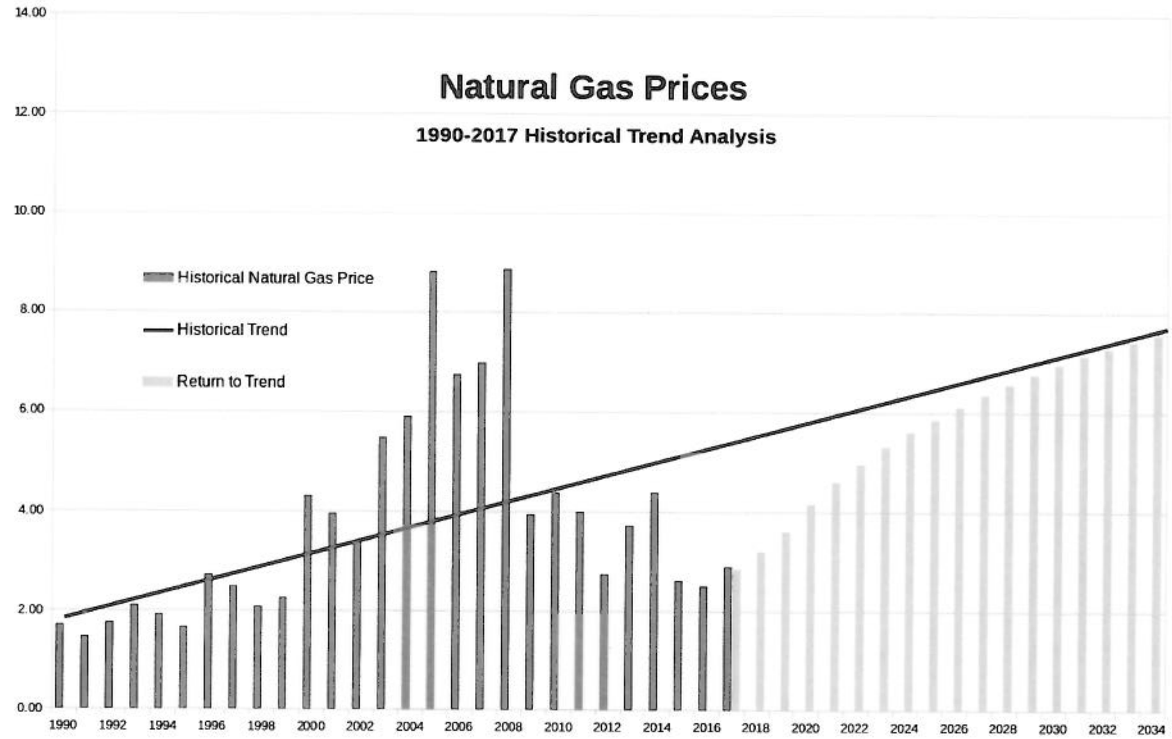
In replacing the nuclear units, customers will benefit from an expansion plan that maintains a high degree of flexibility, rather than locking into a specific fuel source and heat rate, yet the Company's avoided cost analysis completely ignores the risks associated with fossil fuels, and the risks of over reliance on natural gas in the generation portfolio.

No justification has been offered for this sudden lack of concern about these risks, which have not diminished or disappeared. To the contrary, the potential for sharply high natural gas prices continues to exist, and the environmental and political risks associated with carbon dioxide also loom on the horizon.

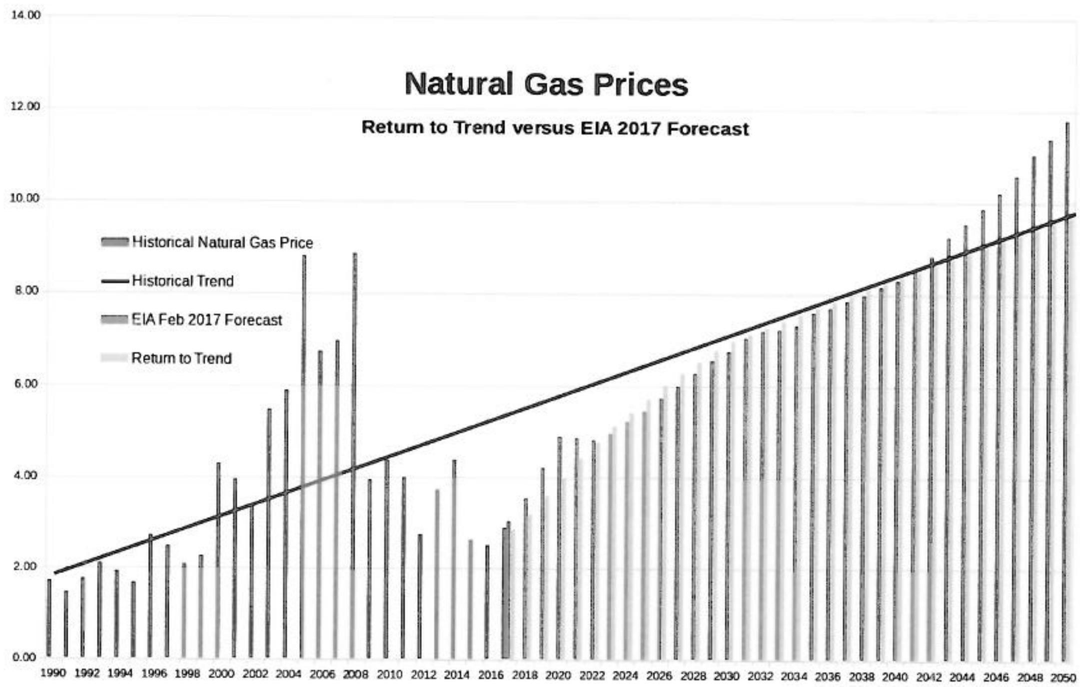
It is fundamentally inappropriate to ignore these risks when comparing scenarios that increase reliance on natural gas with ones that rely more on renewable energy sources like hydro, wind and solar power. Completely ignoring the difference in risks skews the analysis against QF energy, negating consideration of the benefits of being able to purchase power at a guaranteed fixed price.

Q. WHAT FUEL PRICES DID YOU USE TO DEVELOP YOUR AVOIDED ENERGY COST ESTIMATES?

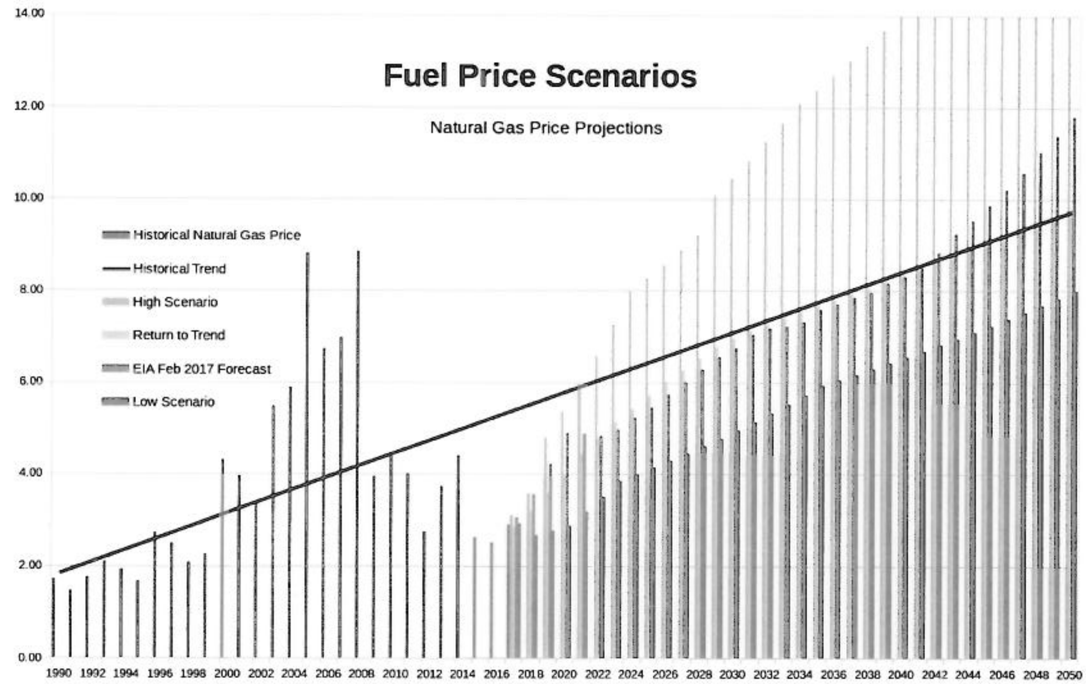
A. I evaluated multiple scenarios, similar to the way SCE&G evaluated its V.C. Summer units. One scenario assumed natural gas prices gradually return to the historical trend line, then follow the trend line, as shown in this graph:



Another scenario was based upon the EIA's 2017 baseline fuel price forecast. As shown in the following graph, the EIA's 2017 forecast is similar to the trend-based scenario, but the EIA forecast is based upon a very detailed analysis of fundamental economic factors, shifting supply and demand conditions, changes in technology, growth exports of Liquefied Natural Gas, and the like. The EIA forecast is generally consistent with the return-to-trend analysis, but their forecast are sometimes a little above, and sometimes a little below, the smoother "Return to Trend" price assumptions.



I bracketed these scenarios with a lower price scenario and a higher one, similar to the approach SCE&G used in its 2015 Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, as discussed above. The lowest price scenario was derived from SCE&G's Scenario 1 and the highest price scenario was derived from SCE&G's Scenario 3. I adjusted both scenarios to lower prices in the initial years, to reflect the 2015, 2016 and 2017 historical data, which wasn't available when SCE&G prepared its V.C. Summer evaluation. All four scenarios are shown in the following graph:



Q. DID YOU MAKE ANY OTHER ASSUMPTIONS RELATED TO FUEL COSTS?

A. Yes. First, I assumed fuel prices would eventually grow at the overall inflation rate (2%) except in the "High" scenario, where I assumed gas prices would increase 0.5% per year faster than the overall rate of inflation. Second, I assumed a heat rate of 6,500 BTU/kWh for the combined cycle unit and 9,750 BTU/kWh for the combustion turbine unit. These are forward-looking estimates which are consistent with what can be achieved with newly constructed generating units. Less efficient heat rates (and correspondingly higher avoided energy costs) would be applicable some of the Company's existing fleet of generating units. Third, I provided an allowance for non-fuel-related variable Operating and Maintenance costs of $2.50 per MWh for the combined cycle unit, $11.00 per MWh for the combustion turbine and $2.35 per MWh for the nuclear unit in 2016 Dollars, before applying a 2% per annum inflation factor. Fourth, I assumed nuclear fuel costs of 1.00 cents per kWh in 2016 Dollars, before applying a 2% per annum inflation factor. This is consistent with, or slightly lower than, the estimates reported by SCE&G in their June 2016 FERC avoided cost report under Subpart C, Section 210 of PURPA.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING RECOVERY OF FIXED ENERGY RELATED COSTS OVER DIFFERENT TIME PERIODS AND SEASONS?

A. As I will discuss later in my testimony, capacity-related fixed costs are appropriately attributed to peak hours and seasons. To some extent, the same logic holds for energy-related fixed costs, which should also be recovered disproportionately during daytime hours, when energy usage is relatively high.

In the Peaker Method, this is typically accomplished by disaggregating the production modeling output during different time periods and seasons, and by focusing on marginal energy costs, rather than average energy costs. Since marginal costs tend to be high during hours when energy usage is high, the Peaker Method allows fixed energy-related capital costs to be recovered on a granular, hour-by-hour basis, following the hourly variation in marginal energy costs. It should be noted, however, this procedure doesn't necessarily ensure that fixed costs are recovered in their entirety.[42]

A variety of different methods can be used to deal with this problem in the context of the DRR method. For my purpose here, I used a similar approach to achieve at least a minimal degree of granularity, and to ensure that all the energy-related fixed costs are taken into account. I first classified fixed costs in excess of the fixed costs of the Combustion Turbine as energy-related, and then took steps to ensure that energy-related fixed costs were largely recovered during times when energy usage is high, rather than at night, when energy usage tends to be lower.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING HOURS OF OPERATION?

A. Coal plants have traditionally been classified as baseload plants, and dispatched before gas-fired combined cycle plants, which have historically been classified as mid-range plants, while combustion turbines are classified as peakers and expected to be dispatched last. However the dispatch sequence can vary with changes in fuel prices and the age of each specific plant. In general, generating plants tend to be dispatched more frequently

[42] In practice, the results of the Peaker Method can sometimes understate costs, since there is no guarantee the energy cost estimates and capacity cost components will be internally consistent, or sum to the full incremental cost of building and operating a new generating plant – as they are theoretically supposed to.

when they are first added to the system and less frequently as they get older, as newer, more fuel-efficient units are introduced to the resource stack. Similarly, gas prices have recently been very low relative to coal prices, causing less efficient coal plants to be dispatched higher in the generation stack (after newly built gas-fired combined cycle plants).

Although somewhat simplified, the approach I used is consistent with the way these different technologies are typically used over their economic life cycle, and it provides a straightforward way of comparing the cost of these different proxy units. However, it is helpful to realize the actual number of hours any given plant will be dispatched will vary as fuel prices change, and it will tend to decline as the plant ages.

I assumed a nuclear unit would be dispatched at the bottom of the generating stack, and its energy-related costs would be recovered during all 8,760 hours per year. I assumed a combined cycle unit would be dispatched in the middle of the stack (below the combustion turbine) and its energy-related fixed costs would be recovered over 5,110 hours per year. [43] Finally, I assumed a combustion turbine would be dispatched last, since it has the highest variable costs. In actual practice, a CT may almost never be dispatched, in which case its energy-related fixed costs will be recovered over very few hours, and

[43] Spreading the energy-related fixed costs over 5,110 kWh per KW of capacity is similar to assuming the Combined Cycle unit will be dispatched approximately 58% of the time, which is reasonably consistent with the overall system load factor.

the resulting level of avoided energy per kWh might be quite a bit higher than what I have presented here.

Q. WHAT CONCLUSIONS DID YOU REACH CONCERNING AVOIDED ENERGY COSTS PER KWH?

A. Avoided energy costs vary widely, depending upon the technology and the future course of natural gas prices. Looking first at a Combustion Turbine, the levelized avoided energy costs (including fuel and variable O&M) will range from less than 4 cents per kWh to more than 11 cents per kWh, depending on the time frame and assumed level of gas prices. This is shown below:

Combustion Turbine Energy-Related Cost per kWh/Year	**Natural Gas Price Scenario**			
	Low	**EIA 2017**	**Return to Trend**	**High**
2017 - 2021 Levelized	3.98 ¢	5.13 ¢	4.65 ¢	5.53 ¢
2022 - 2026 Levelized	5.13 ¢	6.40 ¢	6.55 ¢	8.80 ¢
2027 - 2031 Levelized	6.09 ¢	7.79 ¢	7.99 ¢	11.05 ¢

The sensitivity to the different fuel price scenarios isn't as extreme with the Combined Cycle plant, since it has a better heat rate (burns less fuel) and because the avoided energy costs include some energy-related fixed costs (which don't vary with fuel prices). This greater stability can be seen below:

Combined Cycle Energy-Related Cost per kWh/Year	**Natural Gas Price Scenario**			
	Low	**EIA 2017**	**Return to Trend**	**High**
2017 - 2021 Levelized	3.03 ¢	3.78 ¢	3.45 ¢	4.02 ¢
2022 - 2026 Levelized	3.72 ¢	4.54 ¢	4.62 ¢	6.07 ¢
2027 - 2031 Levelized	4.27 ¢	5.38 ¢	5.49 ¢	7.47 ¢

Together, these avoided energy cost estimates provide a benchmark for comparison with the Company's proposed QF energy rates. As shown, this comparison reveals that the proposed QF rates are significantly less than costs that will be avoided if QF power is purchased to meet retail customer needs, rather than running the Company's existing fleet of generators. Most of the existing generators have heat rates that fall in between the heat rates I used for the Combustion Turbine and Combined Cycle cost estimates.[44]

44 If a new generating unit is expected to be dispatched less than approximately 1,700 hours a year, the benefit of the lower installed cost of the CT outweighs the burden of its higher heat rate and fuel costs.

<u>Proposed QF Tariff Changes</u>

Q. THE COMPANY IS PROPOSING SEVERAL QF-RELATED CHANGES IN THIS PROCEEDING. CAN YOU BRIEFLY DESCRIBE THESE CHANGES?

A. Yes. The Company is proposing major changes to its QF tariffs that would individually and cumulatively have the effect of sending fewer, less precise price signals to independent power producers, and discouraging QF investment.

The first proposal is to stop paying competitors for the use of their energy-generating capacity and to eliminate any compensation for the reliability benefits that QF generators provide during peak usage times. Regardless of the technical arguments for and against this proposal, it is worth noting that it would be intensely and unlawfully discriminatory, since SCE&G would continue to be paid for the use of its energy-generating capacity, unlike its competitors. In addition, SCE&G would continue to be fully compensated for the reliability benefits its generators provide during peak usage times, while its competitors would not receive <u>any</u> compensation for the analogous benefits they provide.

The second proposal is to: "limit the availability of its PR-2 Rate to solar QF's only and to offer separate rates for solar and non-solar QF's in its PR-1 Rate."[45] This seemingly innocuous proposal would have several ill effects. Whatever the intent, establishing an arbitrary distinction between solar and non-solar technologies could have the unintended

[45] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 7.

consequence of creating barriers to competition between these two categories. Furthermore, segregating competitors on separate tariffs that can potentially have different terms and conditions, as well as different rates, may have the effect of skewing the competitive environment in favor of the firms operating on one tariff or the other. This particular proposal also has the effect of creating regulatory uncertainty at the worst possible time – when rapid innovation is taking place that will blur the lines between solar and non-solar technologies.

Making PR-2 a solar-only tariff would also deprive other kinds of QFs of the benefit of standard rates (the PR-1 standard offer tariff, which is not solar-only, is limited to very small generators (100 kW or less)). This would discourage significant investments in non-solar technologies like hydro, biomass and wind.

The proposed "solar-only" rates and methodology are also a bad fit for projects that generate electricity using solar technology but combine it with utility-scale lithium-ion batteries or some other method of storing electricity. This is in part because the Company's assumptions about solar QFs' output profile—assumptions on which the calculation of much lower avoided energy and zero avoided capacity costs are based—simply don't hold when a solar project can use storage to shift the times when it puts power on the grid. These hybrid investments enable competitors to avoid sending power onto the grid at times when a surplus exists, or the power is not as valuable to users, storing it on site, so they can send market the power at a later time, when it is more valuable. This has the potential to benefit firms that invest in these innovative technologies, as well as society as a whole – providing users with the benefit of low-cost, abundant solar energy even when the sun isn't shining. The existing tariffs do not provide strong enough price signals to optimize these types of investments, but at least they provide some incentive for investing in storage. In contrast, the proposed solar rates provide no incentive whatsoever for investing in storage, since they pay all QF's based upon a generic profile, rather than reflecting the actual timing of the energy provided by each individual QF.

The third proposal is to reduce the frequency with which QF rates are updated and refined. This would further enhance the Company's monopoly power, and enable it to more tightly control the process by which QF rates are established, including how often and when rate changes can occur:

> SCE&G also proposes to its update PR-2 Rate going forward only on an "as needed" basis instead of twice a year.[46]

The decision whether a rate change is "needed" would be decided by the Company, rather than ORS or the Commission. Needless to say, it is easy to imagine circumstances where the independent power industry might see a compelling need for refinement or updating of the QF rates while the Company might prefer the status quo and thus refuse to acknowledge that new QF rates are "needed."

46 *Id.*

Q. DO ALL OF THESE PROPOSALS HAVE SIMILAR EFFECTS?

A. Yes. Regardless of the specific details or underlying rationale, if they are approved, they will have similar economic impacts:

- Independent power producers will be discriminated against.
- Competitive risk-taking and innovation will be discouraged.
- The Company's monopoly power will be enhanced.
- Customer exposure to fossil fuel-related risks will increase.
- Renewable energy sources will be suppressed.
- Customers will not gain the full benefit of robust competition.

Q. ARE THERE SOME FUNDAMENTAL REASONS WHY THE COMMISSION SHOULD ENCOURAGE COMPETITION?

A. Yes. Experience has repeatedly demonstrated that, regardless of the goal, government control over economic sectors rarely works as well as market forces to achieve the same goals. Pervasive system-wide failures in places like the Soviet Union, Cuba and Venezuela have vividly demonstrated how poorly government control over the economy works in practice. The experience with more limited controls over specific sectors of the economy is not as bleak, but nevertheless it points to the benefits of effective competition.

Some observers might point to China as evidence to the contrary, but in reality it provides yet another example confirming the same truth. Under Chairman Mao, China fell farther and farther behind Taiwan, although that island had far fewer natural resources. In more recent years, enormous economic gains have been experienced in China precisely because intense monopoly control over the economy by the Communist Party was relaxed, and independent firms were allowed to compete. A proliferation of individual firms (often owned and controlled by individual local governments) began to vigorously compete with each other (and with overseas firms).

As competition increased and monopoly control diminished, competition has begun to play a larger role in determining investment decisions and economic outcomes. While a high degree of government control still exists in China, most people have has benefited as competition has expanded. Individual firms and local communities are being allowed to make independent investment decisions, and they are allowed to share in more of the benefits of their success (and forced to bear more of the burdens of their failures). This has led to much higher levels of investment, innovation and risk-taking throughout the Chinese economy, which explains why we are seeing such rapid growth and improvement in living standards.

While this discussion may seem like a digression, it actually goes to the heart of why I believe the Commission should reject all of the Company's anti-competitive proposals in this proceeding. The public interest is advanced when it is feasible to increase reliance on competition and market-driven economic outcomes, as it is in this proceeding. Among other reasons, competitive processes tend to be more flexible and capable of quickly adapting to changes circumstances and technologies, and they are more capable of inspiring and fostering innovation, creativity, and hard work. More fundamentally, when many different minds are simultaneously trying to solve a problem, and are willing to take different risks, more ideas are generated, more ideas are tested, and there are more opportunities to learn what works and what doesn't.

Conversely, when a single monopoly decision maker controls all of the investment decisions in a particular sector or market, these benefits tend to be lost, and there is a much greater risk of catastrophic failure. Where economic power is intensely concentrated, a single bad decision or judgment call – however well intentioned – can have far-reaching consequences for all concerned.

This is not intended as a criticism of public utility regulation, or a suggestion that regulated monopolies can be completely replaced with competition. My entire 40+ year career has been focused on helping regulators do their jobs as well as possible. Based upon my experience, I am fully convinced that the electrical distribution system (and, to a lesser degree, the transmission system) is a natural monopoly, and that on the whole, rate base regulation has been a highly successful way of handling these natural monopolies.

However, many economists (myself included) have long argued that we can and should improve upon this success story by introducing competition where this is feasible. PURPA is one of cases where government policy makers decided to allow competitive risk taking and innovation, while continuing to regulate remaining parts of the industry. The Commission should use this opportunity to increase competitive pressures in the electric utility industry, and to reduce the need for ratepayers to bear the risks of new generating capacity.

Q. GIVEN THE LIMITED TIME FRAME OF THIS PROCEEDING, SHOULD THE COMMISSION DEFER TO THE COMPANY'S JUDGMENT, ESPECIALLY SINCE THESE ARE HIGHLY TECHNICAL ISSUES?

A. No. This fuel proceeding is being conducted on a highly expedited schedule which does not provide enough time to investigate or even discuss all of these issues raised by SCE&G's filings in complete detail. And in light of this schedule it would be highly inappropriate to give the Company the benefit of the doubt concerning these issues. In my opinion, it would be far preferable to address these issue in a stand-alone proceeding with reasonable time frames and an opportunity for all parties to fully develop the record. This is especially true since the Company's proposed changes are coming at a pivotal time in the transition toward renewable energy sources – a time when rapid innovation and massive investment risks are being undertaken by new entrants. It would be a serious mistake to rush the adoption of these types of changes without adequate study, especially since these changes would shift some policies 180 degrees away from the direction we should be heading.

For instance, the Commission should be moving in the direction of requiring stronger, more precise price signals to help guide competitive investment decisions. Yet, the Company is proposing the opposite: to eliminate the capacity rate, and to make the rest of solar rate structure even less granular than it is now.

Q. WHY ARE STRONGER, MORE PRECISE PRICE SIGNALS PREFERABLE?

A. Prices are vital to the success of competitive markets. They help guide both customers and suppliers. They encourage increases in supply where it is most needed, and they indicate where investment should be reduced or eliminated.

The Company's proposals to weaken price signals will have the effect of blocking these societal benefits. In fact, by eliminating all price signals that indicate when power is most valuable, and by eliminating all payments for the reliability and capacity benefits offered by solar QF's, the proposed solar-only tariffs would discourage solar investments, reduce the incentive for innovators to improve the reliability of their generating system, and eliminate any incentive for competitors to find ways to inject their power into the grid during times when it is most valuable.

Removing price signals, updating QF rates less frequently, and making them less precise are all movements in precisely the wrong direction. Adopting any of these changes at this time would be a particularly unfortunate step for the Commission to take at a time when we are seeing many billions of dollars of new investments flowing into renewable energy technologies worldwide. South Carolina is currently at the leading edge of this worldwide trend, and it is currently benefiting from innovations and investment risk taking by independent power producers who have been attracted by the current regulatory system, which allows them to freely enter the market and compete with the incumbent utilities.

To continue to get the full benefit from these trends, it is important to not erect new barriers to competitive entry, to not create a lot of unnecessary regulatory uncertainty, and to not adopt policy changes that are biased against competitive investments and in favor of rate base investments. Discouraging competitive risk taking will eventually lead to new generating units being put into its rate base, and customers will inevitably shoulder some of the risks associated with those investments. Risks that are partly borne by customers include many of the adverse consequences of poor technology choices, schedule delays, cost over-runs, unexpected price changes, and failed innovations. In contrast, none of these risks are borne by customers when power is obtained from independent power producers, who are paid for output at long-term fixed prices.

It is all too easy to overlook these risks, because they are simply "baked in" to the incumbent utility's retail rates. The adverse risk outcomes are rarely as visible as the problems encountered with V.C. Summer Units two and three. A more typical example is what happened with Duke Energy's Cliffside 6 coal fired generating unit. This costly unit was planned and constructed based upon fuel forecasts that have subsequently proven to be inaccurate. With changes in the relative price of coal and natural gas, the huge investment in advanced coal technology used at the Cliffside plant no longer appears to be as attractive as it must have seemed when it was chosen in lieu of much less costly, ordinary natural gas-fired combined cycle units.

Technology innovations and Investment decisions that seem attractive at the time they are made will often seem less attractive in hindsight. I am not criticizing Duke Energy for betting on a high technology coal plant just before an unexpected era of very low gas prices that wiped out any benefit from this risky investment, any more than I am criticizing SCE&G for betting on nuclear power. My point is simply to remind the Commission that there is a sharp difference between what happens when customers bear these risks and what happens when a QF does.

The Commission can encourage competitive investment by providing independent power producers with stronger, more precise QF price signals. Improved price signals will help them make better decisions concerning where to risk their capital, what specific technologies to use, and what innovation risks to take. This will also put them in a better positions to decide how to respond to future changes in economic conditions and market opportunities, before they emerge. To be clear – I am not suggesting the Commission should become involved with these types of decisions. Rather, I'm suggesting the

Commission should remove the regulatory barriers to sound decision making. Strong, accurate price signals encourage better decisions, which improves the investment climate and leads to better societal outcomes.

Q. CAN YOU RELATE THIS DISCUSSION OF MORE PRECISE PRICE SIGNALS TO THE COMPANY'S RATIONALE FOR PROPOSING TO LOWER SOLAR RATES AND ELIMINATE CAPACITY PAYMENTS?

A. Yes. The Company claims avoided costs are different for solar and non-solar QF's:

> SCE&G must separate solar QF's from non-solar QF's in order to pay each type of QF the correct avoided costs. As more and more solar generation facilities interconnect with SCE&G's system, the benefit of each additional solar generation facility to the Company's system is diminished. SCE&G performed a study titled "Avoided Energy Cost Methods Study for Solar QF's" ("Methods Study") to measure this effect and it is attached to this testimony as Exhibit No. __ (JML-3).[47]

To the extent there is merit to this line of reasoning, the best solution is not to set different rates for solar power, or to arbitrarily assume all solar generators have the same output profile (they don't) or to pay the same rate to solar generators every hour of every day despite the fact that the avoided costs vary widely depending on the time of day and day of the year.

The correct approach is to go 180 degrees in the opposite direction – to make the QF rate

[47] *Id.*

structure more precise, so that differences in output from different technologies, or different generators are automatically reflected in the payments they receive. By moving in the direction of more pricing precision, so that QF rates reflect hour-by-hour differences in the value of power to a greater extent, each QF will receive a different aggregate level of payment, depending on when its output is delivered to the grid. This reform would more precisely match QF rates to avoided costs, and would ensure greater fairness to different types of generators. It would also provide better, more precise price signals to help guide investment decisions, especially with respect to solar plus storage. If the QF is paid more to inject power into the grid at times when the power is most valuable, this will support better decision making concerning how much to invest in generation and how much to invest in storage in solar + storage configurations.

More precise QF price signals will become increasingly beneficial to society as solar grows into a larger share of the overall generation mix. It is readily predictable that in future years, power generated at during the noon hour will not be as valuable as power generating an hour or two later in the day. Power consumption sometimes tends to dip during the lunch hour, while solar output tends to reach its maximum during the middle of the day. The air conditioning load also tends to extend farther into the afternoon beyond the point of maximum solar output, due to the cumulative effect of heat accumulation within buildings over the course of the day. Accordingly, an accurate analysis of avoided costs in five or ten years will show lower costs in the middle of the day than later in the afternoon. With accurate QF rates reflecting this evolving cost pattern, solar generators would have an incentive to add storage as the "duck curve" emerges. With strong, precise price signals, both society and the QF would benefit by taking advantage of the opportunity to store power in the middle of the day, and send it to the grid when it is more valuable, later in the afternoon or early evening.

Q. EARLIER IN YOUR TESTIMONY YOU MENTIONED HOW FIXED COSTS RELATE TO ENERGY COSTS. CAN YOU ELABORATE ON THESE CONCEPTS, AS THEY RELATE TO IMPROVED PRICE SIGNALS?

A. Yes. With a more sophisticated rate design that closely aligns with hourly and seasonal variations in avoided energy and capacity costs, all types of QF's will be treated fairly, each type of QF will be paid the right amount, and all types of competitors will be provided with an appropriate – but not excessive – incentive to invest in storage technologies. All of this will further improve societal outcomes – most obviously by enabling abundant, low cost solar energy to be used in the late afternoon, early evening, and early morning, if the energy is needed, or is more highly valued, during those times.

Q. IF AVOIDED CAPACITY COSTS ARE MOSTLY FIXED COSTS, CAN YOU EXPLAIN HOW THESE COSTS BE TRANSLATED INTO DIFFERENT RATES AT DIFFERENT TIMES AND DURING DIFFERENT SEASONS?

A. Yes. However, before answering this question in detail, I should mention that the relationships between fixed costs and prices, as well as the specific problem of how best to recover "capacity-related" avoided costs under PURPA are surprisingly complex issues, which can easily become confusing. The pricing issues are intertwined with subtle distinctions between capacity costs and fixed costs which can best be explained by first explaining how joint and common costs are recovered under competitive conditions. In turn, this competitive example provides clear guidance concerning the optimal way of recovering capacity-related costs during different hours of the day, and days of the year.

Although the issues are quite complex, they are well worth exploring in detail, since they are of pivotal importance to the future of the solar industry. In the context of a regulated monopoly, it wasn't always necessary to be concerned about setting precise price signals, or resolving the best way to recover fixed costs through per-kWh prices. Typically, the benefits of administrative convenience outweighed any need to be concerned about setting optimal, or even very accurate prices. However, with QF prices, the rates set by this Commission will influence billions of dollars of investment. Improving these price signals will help improve those investment decisions, avoid excessive amounts of investment (the boom and bust phenomena that occurs in some markets) and help avoid or overcome the problems SCE&G identified in the studies it submitted in support of its proposed QF tariff changes.

Q. YOU'VE MENTIONED SEVERAL TYPES OF COSTS. SOME OF THESE TERMS ARE LESS FAMILIAR THAN OTHERS. CAN YOU PROVIDE SOME DEFINITIONS?

A. Yes. In economics, the most fundamental and important types of costs are fixed cost, variable cost, total cost, average cost, marginal cost, incremental cost, and stand-alone cost. All of these are integral parts of economic theory – along with other, more specialized cost concepts, including sunk, direct, joint, and common costs. All of these cost concepts are significant to the issues in this proceeding.

Fixed costs do not change with the level of production, during the planning period or "run" under consideration. **Variable costs** change directly (but not necessarily proportionately) with the level of production. It should be noted that the exact same item might be a fixed in the short-run and a variable in the long-run. Together, fixed and variable costs constitute **total cost**, which is the sum of all costs incurred by the firm to produce a given level of output. Dividing the total cost of producing a given volume of output by the total number of units produced, one can calculate **average total cost**.

Short-run costs are those which arise in situations where most costs are fixed. In contrast, **long-run costs** are those calculated under the assumption that many, if not all, costs are variable, and relatively few costs are fixed or sunk. The classic long-run concept is sometimes known as a "scorched earth" approach – that is, no pre-existing plant is considered in the analysis. Instead, the firm is free to build precisely the size and type of plant which best fits the assumed output level. However, even in the long-run some aspects of the production process are typically assumed to remain inflexible – like the technology the firm uses, or the state or region where the firm operates.

Incremental cost is the change in total cost resulting from a specified increase or decrease in output. In mathematical terms, incremental cost equals total cost assuming a specific increment of output is produced, minus total cost assuming the increment is not produced. Incremental cost is often stated on a per-unit basis, with the change in cost divided by the change in output. Incremental cost can vary widely, depending upon the increment of output under consideration. If the entire increment from zero units to the total volume of output is considered, incremental cost is identical to total cost. Similarly, where the increment ranges from zero to total output, incremental cost per unit is identical to average cost per unit for that volume of output. Because a wide variety of different increments can be specified, a wide variety of different incremental costs can be calculated. Thus, in considering any estimate of incremental cost it is crucially important to determine whether or not the specified increment is relevant to the issues at hand.

Marginal cost is the same as incremental cost where the increment is extremely small (e.g., one unit) and the cost function is smooth and continuous. In mathematical terms, marginal cost is the first derivative of the total cost function with respect to output (the rate of change in total cost as output changes).

Common costs are incurred when production processes yield two or more outputs. They are often common to the entire output of the firm but can be common to just some of the outputs produced by the firm. An increase in production of any one good will tend to increase the level of common costs; however, the increase will not necessarily be proportional. The costs of producing several products within a single firm may be less than the sum of the analogous costs that would be incurred if each of the products were produced separately (this is referred to as economies of scope).

Joint costs are a specific type of common cost—they are incurred when production processes yield two or more outputs in fixed proportions. A classic example arises in the joint production of leather and beef. Although cattle feed is a necessary input for the production of both gloves and hamburgers, there is no economically meaningful way to separate out the feed costs that are required to produce each. If the quantity of leather and beef is reduced, there will be a savings in the amount of cattle feeding costs, but it is impossible to say how much of this change in cost results from the change in the quantity of leather, and how much from the change in the quantity of beef.

Q. WHY ARE JOINT COSTS RELEVANT TO THIS ISSUES IN THIS PROCEEDING?

A. In the electric utility industry, the cost incurred in creating the capacity (or ability) to generate, transmit, or distribute electrical energy are joint across time. To draw a comparison, there is a clear parallel between the cost of cattle feed and the cost of generating capacity. Expenditures that increase the quantity of beef invariably tend to increase the quantity of hides that are available, as well. The specific quantities may not be identical, and it is conceivable that some of the hides might get thrown away, but the production proportions themselves tend to be inextricably linked and highly stable (it is not easy to vary the proportion of beef and hides). Similarly, an investment that results in the capacity to generate a certain number of kWh of electrical energy from 2 pm until 3 pm on Mondays will very likely result in the ability to generate the exact same number of kWh of energy from 2 pm until 3 pm on Tuesdays, and the rest of the week, as well.

In fact, the problem of joint costs across time is so pervasive, it is easily overlooked. Once money is spent on the ability to generate electricity on a hot summer afternoon, the same capability exists and is available during cool spring afternoons, and cold winter mornings, as well. Depending on the specific technology, there may be limitations and differences in the engineering proportions, but the joint cost concept still applies. For instance, due to temperature differences, a combined cycle plant may provide more energy generating capacity during a cold winter morning than during a hot summer afternoon – the proportions are not precisely one-to-one, but they are nevertheless relatively fixed, and cannot easily be varied.

The fact that fixed costs do not (by definition) vary with output, and because of the existence of a pervasive joint cost problem across different time periods, QF rates involve a situation where many costs cannot accurately and easily attributed to a specific hour of the year, or a specific kWh. While it is sometimes argued that all capacity related costs should be attributed to the single highest peak hour of the year, upon further thought, most knowledgeable observers realize this is not, and cannot be, the correct pricing solution. By this logic, a supplier would attempt to charge an extremely high price during the one highest peak hour of the year, and it would charge nothing during the remaining hours. Upon reflection, it is obvious that many customers would not be willing to pay this extremely high price (it would be something on the order of $60 per kWh), and so many users would conserve, or stop using electricity during that one hour. If even a few users react this way, usage would drop sharply, and this hour would no longer be the peak hour – the highest rate of usage would simply occur during a different hour.

Q. WHAT DOES ECONOMIC THEORY TELL US ABOUT HOW JOINT COSTS ARE RECOVERED IN COMPETITIVE MARKETS?

A. Joint costs create a challenging puzzle for economic theory: it is not immediately obvious how joint costs are recovered in competitive markets, since they do not show up in the marginal costs which normally explain how prices are determined. The solution to this puzzle, which was discovered in the early 1900's, sheds light on how more precise capacity rates can be developed, as well as yielding some useful insights into why the Company's argument against making capacity payments to solar generators is flawed.

Decades before the joint cost puzzle was solved, economists had figured out that prices tend to equilibrate to a level that is equal to marginal cost. In fact, in situations where firms are accepting a market-determined prevailing price, marginal cost is the key to understanding how that prevailing price is established. Among other insights gleaned from this analysis is that average cost is much less important than marginal cost.

A classic example is a wheat farmer. A wheat farmer has no control over the weather, and no control over the price of wheat, which is decided through nationwide forces of supply and demand. Hence, he concentrates on optimizing those aspects of his production function that he can control (deciding how many acres to plant, what crop rotation system to use, what seed to plant, how much fertilizer to use, how much to irrigate) in an attempt to maximize profits.

Like all competitive firms, wheat farmers make these types of decisions based on an analysis (whether explicit or implicit) that is tightly linked to marginal cost, rather than average cost. The firm increases each factor of production beyond the point of diminishing returns, until the point where the marginal revenue product associated with each input is equal to marginal resource cost of that input. While each firm makes these decisions independently, their individual decisions collectively lead to a convergence of industry-wide prices and marginal costs. In fact prices will exactly equal the industry-wide level of short-run marginal cost if the industry is in short-run equilibrium, and prices will equal long-run marginal cost if the industry is in long-run equilibrium. In equilibrium, every firm's marginal cost will exactly equal every other firm's marginal cost, despite wide differences in their individual circumstances, like the fertility of their soil, the types of equipment they use, and other details of their production function, and despite the lack of any coordination in their individual production decisions.

Because joint costs do not directly vary with the output of any one product, they are an exception to this general pattern, and it is not self-evident how they are recovered from customers. Among other insights that can be gleaned from solving the joint cost puzzle is that the general equilibrium conditions that were just described are not achieved exclusively by costs being adjusted to match prices. To some extent, the process also works in the reverse direction: prices also tend adjust to the level of marginal costs incurred by the typical firm. Decisions made by both producers and consumers are important in establishing prices in competitive markets. Succinctly stated, the interaction of both supply and demand determines what costs are incurred by producers and what prices are paid by consumers.

Q. WHAT IS THE SOLUTION TO THE JOINT COST PUZZLE?

A. The solution is straightforward, but not obvious: in competitive markets, relative levels of value – or benefits – largely determine the share of joint costs recovered from each of the joint products. If two products are jointly produced, the most valuable product, or the one that receives the largest benefit from the joint production process, will pay the largest share of the joint costs. The least valuable product, or the one that receives the smallest benefit from joint production, will pay the smallest share.

Recall that joint costs are incurred when production processes yield two or more outputs in fixed proportions. Two classic examples are the production of beef and hides and the production of cotton and cottonseed. The costs of raising and slaughtering cattle are part of a joint production process that produces both meat and hides, in relative proportions than cannot easily be adjusted by the cattle farmer. Similarly, cotton and cottonseed oil are both part of a joint production process, in proportions that cannot be easily adjusted.

The cost of fattening and slaughtering cattle are paid by consumers of both beef and hides, while the cost of growing and harvesting cotton are recovered from consumers of both cotton and cottonseed oil, in proportions that depend on the relative value of each of the joint products (not their respective marginal costs). For example, if hamburger is not highly valued (because consumers don't particularly like hamburger, or they prefer chicken or seafood), but leather is highly valued, a surprisingly large fraction of the cost of cattle feed may be borne by the purchasers of leather goods. Similarly, if the purchasers of gloves are willing to pay more for leather gloves than for cloth gloves, they may end up paying a relatively large share of the cost of cattle feed while the purchasers of cotton gloves may pay a relatively small share of the cost of growing cotton (and consumers of cottonseed oil may pay a larger share than might otherwise be expected).

Once the solution to the joint cost problem is explained, many people find it intuitively logical and reasonable. The purchasers of both leather gloves and hamburgers both benefit from the joint cattle feeding and slaughtering process, so it makes sense that both will contribute to the joint production costs. Similarly, the demand for both beef and leather products is strong, so it seems logical that market forces would lead consumers of both sets of products to contribute toward the joint costs of raising and slaughtering cattle.

Different customers pay different amounts, depending on how much benefit they derive from the joint production process. Those consuming the most highly valued products (for which demand is strong) will pay the largest share of the joint costs, while those consuming the least valuable products (for which demand is weak) will pay the least. This principal applies not only to the distinction between beef and hides, but also to different types of beef, or different sections of the hide. A customer that purchases hamburger will end up paying more per pound toward the joint costs of cattle production than one who purchases standing rib roast or filet mignon.

Q. WHAT ARE THE IMPLICATIONS OF THIS ANALYSIS FOR THE ISSUES IN THIS PROCEEDING?

A. Electrical energy production is a joint product when viewed across time. Capacity used to generate electricity during the peak daytime hours is also available for use during other hours. Under competitive conditions, when costs are joint across time, they will not be borne exclusively by users in any single time period. We can go beyond this to also note that the joint cost recover will not be equal in every hour of the day or year. To the contrary, more of these fixed costs will be borne by users in the peak hours – when demand for electricity is strongest, and most users value it especially highly. A smaller share of the capacity costs will be incurred late at night, and during the off-seasons like spring and fall, when the weather is mild and the demand for electricity is relatively low.

The joint cost recovery pattern observed in competitive markets is highly significant, and it can appropriately be used by the Commission to help guide the way it sets QF capacity rates. Following the standard solution – recovering more capacity costs at times when demand is high, yet also recovering a small share of these costs at times when demand is low – provides economically sound price signals that will help guide competitive investment decisions.

Q. CAN YOU CLARIFY WHY A SOLAR GENERATOR SHOULD BE PAID MORE THAN THE SHORT RUN MARGINAL COST OF ENERGY?

A. In markets where joint costs are not significant, prices tend to equilibrate to marginal cost. However, in markets (like electricity) where joint and common costs are pervasive, total costs cannot be recovered using pure marginal cost based prices. Instead, prices must include a markup above marginal cost, to provide a mechanism for the recovery of joint and common costs. The cost recovery pattern is clear and consistent across all types of markets where joint costs exist: recover the variable direct costs incurred by producers – short run marginal costs – plus a contribution toward their otherwise unrecoverable indirect, joint and common costs. The amount of that contribution will vary depending on market conditions, the strength of demand for different products or services, and the level of marginal costs incurred by a specific firm relative to other firms. Producers are paid based upon the value of what they produce, not based upon their internal cost characteristics. A firm with high marginal costs (and low fixed or joint costs) might receive very little markup above their marginal cost. Another firm with very low marginal costs but high fixed costs, would be paid an equivalent price for their production, but that price would involve a large markup above their marginal cost.

In competitive markets, there are market forces that push prices toward short-run marginal cost. However, there are other market forces that will push prices toward a long-run equilibrium level that exceeds this level, if this is necessary to ensure that each price includes an adequate contribution toward joint and common costs, so that a typical firm can recover its total costs, including the costs associated with long-term capital investments. In competitive markets, demand conditions help determine the extent to which the firm's costs are recovered from specific products or services, and the extent to which its costs are recovered from specific customers or customer groups.

More specifically, if purely marginal cost-based prices would not be sufficient to ensure adequate total cost recovery, prices will instead equilibrate (in the long-run) toward levels that exceed marginal cost by the amount necessary to enable the typical firm to recover its joint and common costs. Significantly, this demonstrates that competitive prices are not purely a function of marginal cost.

By analogy, under competitive conditions, the fact that a particular firm has marginal costs of zero would have no relevance to the revenues it would obtain. The price it is paid is based on the interaction of supply and demand for the market as a whole. If the product it produces is valuable, it will be paid for that value, even if its marginal cost is zero. Consider again the example of cotton and cotton seed. A firm that spins cotton into cotton cloth may consider the seeds a mere byproduct – something that costs them nothing, since they came for free with the cotton they purchased from farmers. Nevertheless, if other firms find a valuable use for cotton seeds (converting them into oil), the amount paid for the seeds will be purely a function of their value when turned into oil – and the payment received by the cotton mill will represent pure markup over their marginal cost, which is zero in this example.

The same principle applies to the production of electricity. A solar generator should be paid for the value of the electricity it provides, as well as the reliability benefits it offers by producing power at times when electricity is highly valued and needed by users. In turn, this provides a cost recovery mechanism that enables the generator to recover some the fixed costs of its investment – with the highest revenues being generated during hot summer afternoons, and lower revenues during a cool fall afternoon. Similarly, with appropriately structured QF capacity rates, firms that invest in storage technology will have the option to shift some of their output from hours when electricity is less valuable to hours when it is more valuable. Accurate, time-sensitive price signals will encourage a market-driven response to those price signals, encouraging investments in storage, and helping independent power producers with storage to determine how to use their storage capacity to gain the maximum benefit for them and for society.

Q. ARE YOU SUGGESTING THAT MARGINAL COSTS ARE IRRELEVANT?

A. None of this discussion in any way suggests that marginal (variable) costs are irrelevant. Recall that under competitive conditions both supply and demand are important. Producers respond to prices, and prices are determined by market forces, with the interaction of supply and demand determining the relative share of joint costs that are provided from the joint products. In this context, that means that users of electricity during different hours will make different contributions above marginal cost.

In general, the amount paid during specific hours will vary depending on the strength of demand during those hours, and the amount received by specific producers will depend on their willingness and ability to meet market demand during those hours. It is during hours with the strongest demand – and in that sense, the greatest benefits from the joint production process – when the greatest share of joint costs will be borne. In turn, this determines what share of the joint costs are recovered from different users, but all users of electricity end up contributing to the recovery of the joint costs.

To the extent different types of users have different usage patterns, they will make different contributions. For instance, an industrial user that consumes a lot of electricity late at night, and especially if it is willing to be interrupted during peak hours, will pay relatively little per kWh for its electricity, compared to a retail store that only operates during daytime hours and uses a lot of air conditioning on hot summer afternoons, when the demand for electricity is high.

Similar disparities exist on the production side of the supply and demand equation. Different competitors may use different technologies to produce essentially the same product, in which case they will have different cost functions, and incur different levels of marginal cost. The revenues received by firms with low marginal costs and high levels of fixed or joint costs can still compete with firms that have a higher level of marginal costs and lower fixed or joint costs. In both cases, prices may involve a markup above marginal cost to recover fixed or joint costs, but the magnitude of that markup may will depending on their particular cost function and circumstances.

In the electrical context, we can anticipate that generators with high marginal costs will only operate during hours when demand is strong, and the going price exceeds their marginal costs. They may cease production entirely during some months of the year when demand is weak, or at night, when prices fall below their marginal cost.

Q CAN YOU ELABORATE ON THE IMPLICATIONS OF JOINT COST RECOVERY PATTERNS FOR THE ONE OF THE KEY ISSUES IN THIS PROCEEDING: WHETHER QF RATES SHOULD INCLUDE PAYMENT FOR THE VALUE OF CAPACITY THEY PROVIDE?

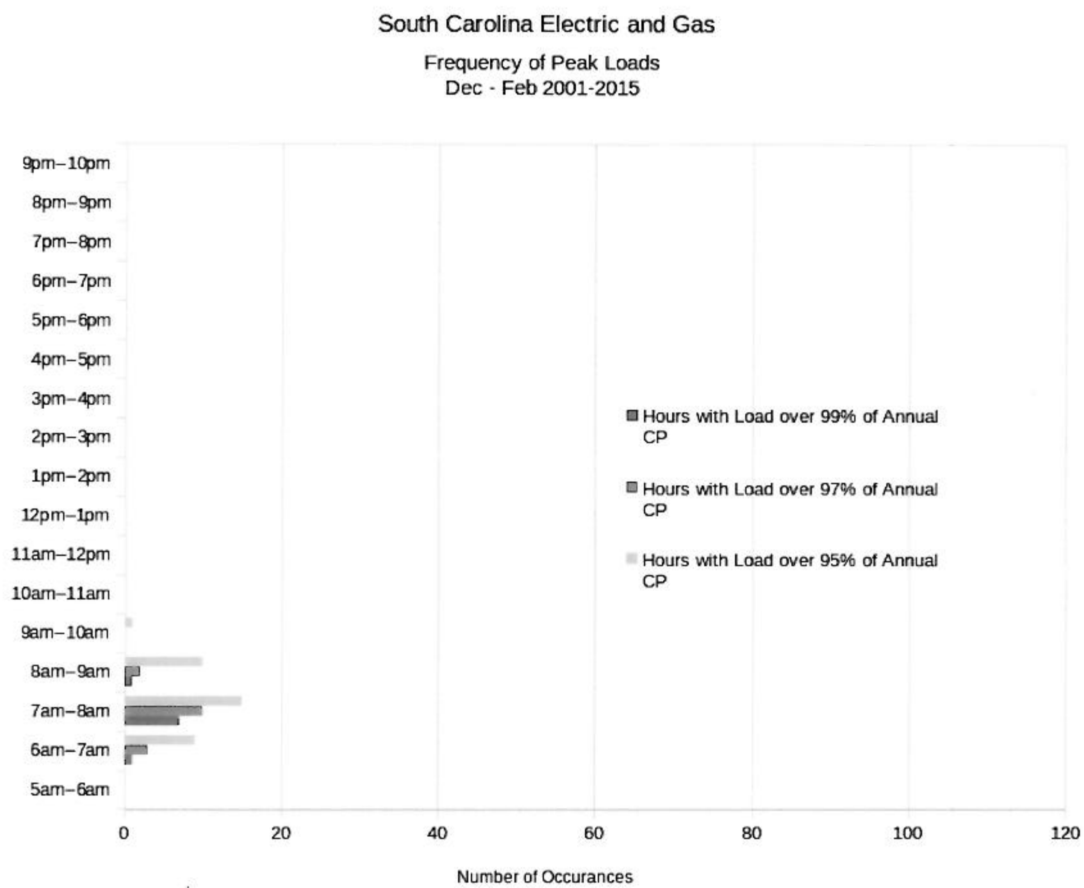
A. Yes. The Company argues against making any payment to solar generators for the capacity benefits they provide – including electricity that is delivered to the grid on hot summer afternoons, when it is highly valued by users, and their capacity is very beneficial in helping to meet the need for electricity. Their reasoning is as follows:

> Since SCE&G's Reserve Margin Study shows that SCE&G needs as much capacity in the winter as it does in the summer, a resource has to provide capacity in the winter as well as the summer in order to avoid the need for capacity and thereby have capacity value. Because solar does not provide capacity during the winter period, the Company is unable to avoid any of its projected future capacity needs and, therefore, the avoided capacity cost of solar for these winter months is zero.[48]

Before discussing how this relates to joint cost recovery, I would first point out that this fundamental premise is wrong. SCE&G does not have an equal need for capacity in the winter and in the summer. This can easily be confirmed by studying a few graphs.

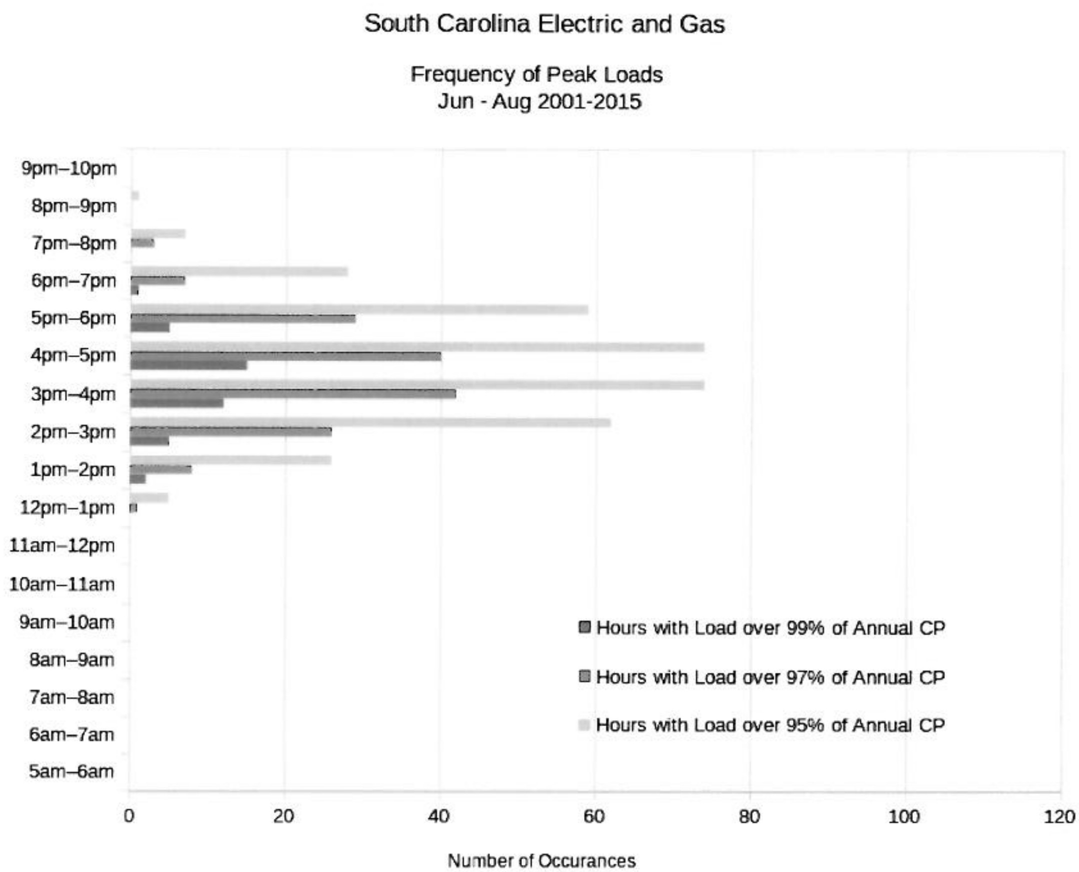
48 *Id.*, Page 16.

1 This first graph shows the number of hours when peak levels of usage occur during
2 winter months.

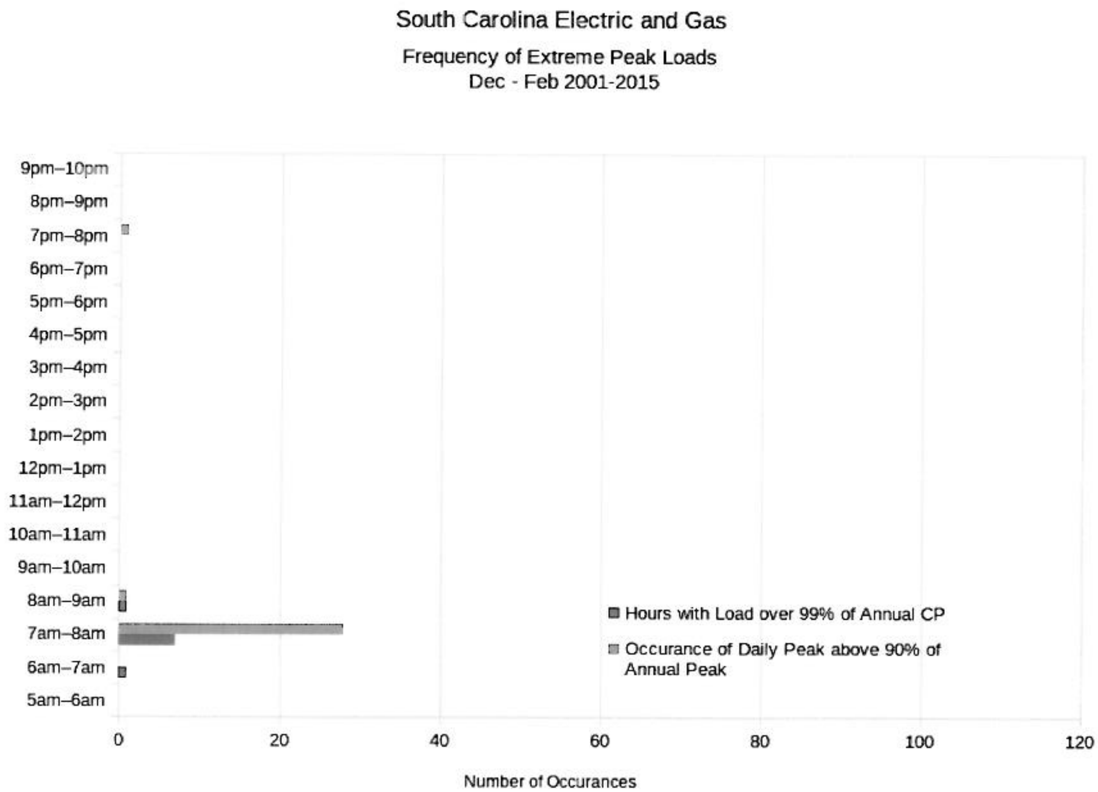


3

This second graph shows the analogous data for summer months.

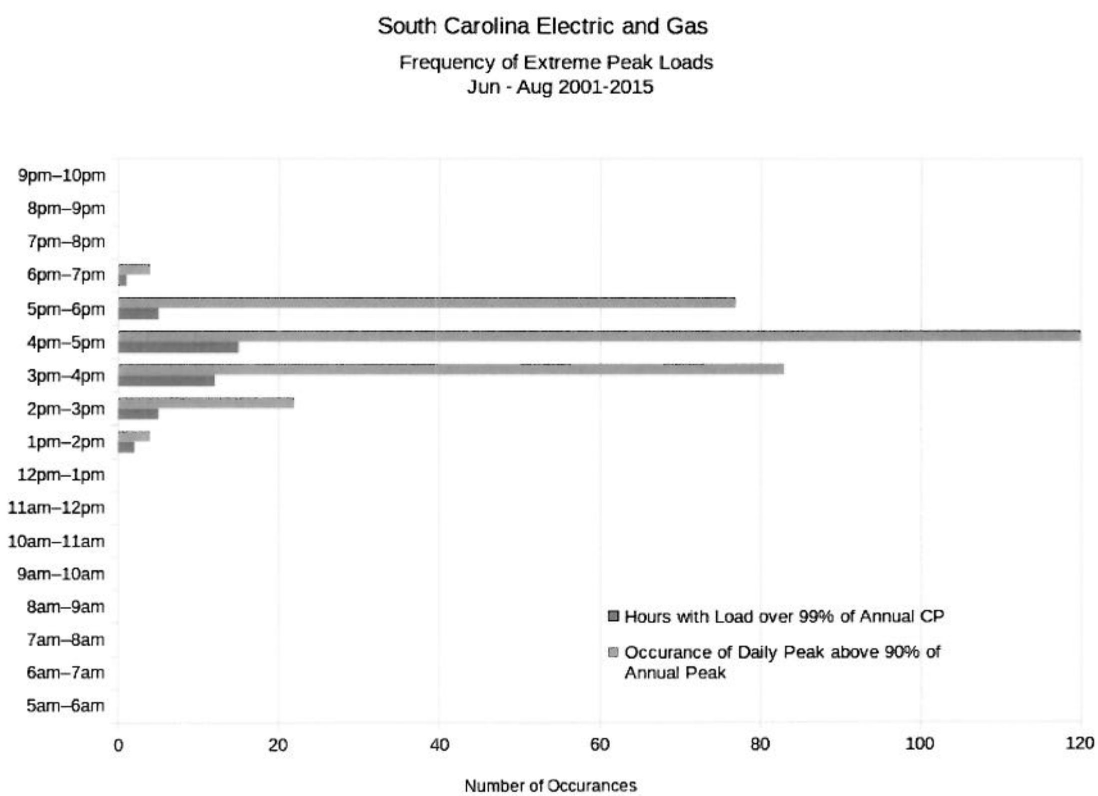


Comparing these graphs, it is clear that peak levels of energy usage occur much more frequently in the summer months than in the winter months. The same conclusion can be reached by focusing on the most extreme peaks. This third graph shows extreme winter peaks:



However, the fourth graph (on the following page) shows a much greater intensity and frequency of extreme peaks during the summer.

The Company is primarily a summer-peaking utility, the demand for electricity is generally stronger in the summer than in the winter, and both common sense and economic theory tell us that capacity costs should mostly be recovered from customers who are using electricity during high demand periods in the summer – not from users late at night, or during mild spring and fall days. The principles of joint cost recovery tell us not to take this reasoning too far, however. It would not be logical, fair, or appropriate to demand that the recovery of fixed capacity costs be 100% concentrated during the most extreme peak hours on summer afternoons, as shown on this fourth graph:



Demand is very strong during these hours, and the value of energy generating capacity is very high during these particular hours, most of which are times when solar output is very high. Nevertheless, it is important to recognize that users benefit from generating capacity that is available during many other, lower usage, hours as well. The logic of joint cost recovery tells us that a reasonable share of the annual fixed costs of capacity should also be recovered during many other hours of the year – including the early morning hours of December through February, when extreme peaks also sometimes occur.

Q. SHOULD SOLAR AND NON-SOLAR GENERATORS BE PAID DIFFERENT PRICES?

A. No. In competitive markets, users pay for what they value. This is fair to the users and fair to the producers. No one penalizes a firm for using the "wrong" technology – except to the extent their technology decision results in them producing a product that is less valuable than if they made a different choice. The engineering characteristics of individual firms or technologies are irrelevant except to the extent they impact the way they choose to operate, or the value of energy they produce, which can vary depending on the hours when it is produced. Some types of generators (like nuclear) can operate 24 hours a day, but a lot of their energy is produced late at night, when demand for electricity is low. Other generators (like solar) can only operate during the daytime hours, but their production occurs when demand is strong. Both types of generators should logically be paid for the value of what they provide, when they provide it.

Q. IF A SOLAR GENERATOR CAN'T PROVIDE ENERGY DURING THE EARLY MORNING HOURS OF THE WINTER, DOES THIS JUSTIFY PAYING NOTHING FOR THEIR CAPACITY DURING THE REST OF THE YEAR?

A. No. Under joint cost recovery principles, there is no logical reason to require a supplier to provide service during winter mornings in order to receive payment for the reliability and capacity benefits they provide during summer afternoons.

Each generator should be compensated for the value of what it brings to the market. Generators that operate during both the summer and winter peaks quite properly should receive higher payments than those that only operate during one season or the other, since because they provide benefits during both seasons. But, it is not logical, or reasonable, or consistent with economic theory to refuse to pay a generator for a valuable service they are providing during the summer merely because they aren't also providing a similar service during the winter.

Q. CAN YOU COMMENT FURTHER ON THE NEED TO MEET EARLY MORNING PEAKS IN THE WINTER?

A. Yes. The need for generating capacity during the early morning hours in the winter is a very small part of a much bigger picture. Capacity needs exist throughout the year, and those needs can and should be met on a pooled basis, using an entire portfolio of resources. This is analogous to the way securities become more valuable when they are combined with other types of securities, in an overall portfolio. A growth stock may not provide any immediate income, but that doesn't mean it doesn't belong in the portfolio. No single security meets every need, yet each one can bring a different form of value to the portfolio. Similarly, generators should be evaluated in terms of the contribution they provide to the overall portfolio of generating resources. In this regard, this passage in the Company's testimony is revealing:

> Since SCE&G's need for capacity spans the entire year, it is necessary to spread avoided capacity costs throughout the year to reflect the Company's reliability risk as explained in the Reserve Margin Study.[49]

Some generators, with high marginal costs, may be operated during few hours of the year, yet they still bring value to the overall portfolio. It is reasonable for retail customers to pay the fixed costs of these rarely used generators, because they provide a backup source of power, and enhance overall reliability. Similarly, it is self-evident that generators that operate during hundreds or thousands of daytime hours are contributing very substantial value to the overall generating resource portfolio, notwithstanding the fact they do not operate at night, or during the early morning hours.

[49] *Id.*, Page 23.

Q. ARE THERE INEXPENSIVE WAYS OF MEETING EARLY MORNING PEAKS IN THE WINTER?

A. Yes. While the need is real, it is actually a fairly easy problem to solve, because the peaks are of such short duration, and they occur so infrequently, (as can be seen in winter graphs above). The cost of meeting this need can be held far below the full annual cost of building and operating a generating unit. One potential solution is hinted at in this passage from the Company's Reserve Margin Study:

> ...very cold weather can make SCE&G's winter peak spike for an hour or two. A peak clipping resource available for a few hours may be better suited to address this risk than a generating unit.[50]

For example, large industrial customers might agree to an interruptible rate, which will provide them with a financial incentive to risk being interrupted a few hours per year, but only on cold winter mornings. This type of narrowly targeted "demand management" resource would likely be a very low cost option, since the frequency of interruption would be low, and there would be plenty of warning before any interruption – the risk only occurs during a handful of early morning hours during extreme cold snaps.

This is not the only option, however. Peaking units that are primarily in the portfolio for reliability purposes could also be operated during this small number of hours. Similarly, the need could be met by purchasing blocks of firm energy and capacity on the wholesale

[50] SCE&G 2017 Reserve Margin Study, Page 2.

market, where the purchases are narrowly targeted to winter mornings. This option is likely to be very cost effective, since SCE&G is located in close proximity to the PJM power market. This is an extremely large, very liquid wholesale power market, which is primarily summer-peaking. Peak generators that obtain most of their revenues and profits from the summer months are in a good position to sell firm capacity during early winter mornings, without detracting from their main revenue stream.

Finally it is worth noting that the Company's Fairfield Pumped Storage unit can also fulfill this need. The reservoir can be filled overnight, and the water used to generate electricity during the early morning hours, when people are waking up and turning up their thermostats. This brief surge in demand is relatively sudden and relatively brief. That makes it an ideal match to the capabilities of the pumped storage unit, which offers a large amount of peak capacity, provided it is only operated for a short period of time. After a few hours, all of the water will run out.

Q. WHAT CONCLUSIONS SHOULD BE DRAWN FROM THIS DISCUSSION?

A. The Company's arguments for paying solar generators less than non-solar generators should be rejected. All QF's should be paid the full amount of energy and capacity costs they help avoid. Differences in payments to different generators should be based upon the differences in the hours when they operate, paying less for hours when demand is weak and more during hours when demand is high.

Consistent with this reasoning, the Company's arguments for not paying capacity rates should also be rejected. All QF generators provide valuable capacity benefits when they operate during daytime hours. Those benefits are especially strong during hot summer afternoons, when the demand for energy is strong, which also happens to be a time when solar output is high. To refuse to make any capacity payments or to recognize any of the capacity costs that are avoided when QF generators operate during these hours is highly discriminatory and fundamentally wrong.

The mere fact that particular generators do not operate during a small number of unusually cold, early-morning winter hours is not a valid basis for refusing to pay QF's for the capacity benefits they provide throughout the rest of the year.

Avoided Capacity Costs

Q. HAVE YOU DEVELOPED ESTIMATES OF THE COMPANY'S AVOIDED CAPACITY COSTS?

A. Yes. I developed some benchmark avoided capacity cost estimates using the Proxy Unit method. The first estimate is based on a hypothetical nuclear plant, similar to the V.C. Summer project. The second estimate is based on a hypothetical Combined Cycle plant. The third estimate is based on a hypothetical Combustion Turbine.

Q. BEFORE DISCUSSING YOUR COST ESTIMATES IN DETAIL, CAN YOU BRIEFLY SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S AVOIDED CAPACITY COSTS?

A. Yes. These calculations show that SCE&G's current rates are already well below the long run fixed costs of building and operating any of these three types of generating units over their economic life. It would not be reasonable to make any further reductions to these rates. Rather than reducing the QF capacity rate to zero, it would more be appropriate to increase the rate at least modestly, to be more consistent with the long run incremental cost of new capacity, while paying the capacity rate to QF's only during hours when their energy is making a valuable contribution toward meeting the Company's peak loads. This would better encourage QF development within SCE&G's service area, which would be consistent with the intent of PURPA and FERC's rules, would help lower retail rates over the long run, and help advance the public interest.

Q. CAN YOU BRIEFLY EXPLAIN HOW YOU ESTIMATED THE COST OF CONSTRUCTION FOR A NEW NUCLEAR GENERATING UNIT?

A. In my avoided cost analysis I assumed an installed cost of $5,350 per kW for a newly constructed nuclear unit. I developed this number by looking at publicly available information concerning construction costs, including cost estimates for the V.C. Summer nuclear plants prior to the time when SCE&G cancelled them.[51] I started with the $7.6 billion cost estimate for the V.C. Summer units, which was provided in the Company's June 2016 PURPA filing. However, I also considered the most recent available cost estimate published by the Energy Information Administration ("EIA") for new nuclear construction, which I adjusted to 2017 dollars using an annual inflation rate of 2.0% and to reflect local cost conditions using their state-specific cost adjustment factor.

Nuclear	Cost per kW in (2017 Dollars)
Proxy Unit	$ 5,350
EIA – Advanced Nuclear [52]	$ 5,652
SCE&G – Summer June 2016 Estimate	$ 5,307

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBINED CYCLE UNIT?

A. I started with an installed cost per KW in 2017 dollars of $1,050. This is slightly higher than the $993 figure SCE&G used as an input in its avoided cost calculations. The $1,050

[51] The Company's June 30, 2016 avoided cost filing in compliance with Subpart C, Section 210 of PURPA indicates the Company's next planned generating unit is VC Summer #2, which is projected to add 625 MW of capacity in 2020, 22 MW of capacity in 2021, and 23 MW in 2022. VC Summer #3 is expected to add 648 MW of additional nuclear capacity in 2021 and another 22 MW of capacity in 2022, for a grand total of 1,340 MW.

[52] See Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 ("2016 EIA Report"), Page 7. These calculations apply EIA's 4.9% location adjustment factor for South Carolina (Page A-20) and adjust for inflation at 2% per year.

figure is consistent with multiple publicly available data sources:

Combined Cycle	Cost per kW (2017 Dollars)
Proxy Unit	**$ 1,050**
EIA – Advanced CC[53]	$ 1,126
Duke – Dan River CC[54]	$ 1,007
Duke – Buck CC[55]	$ 1,060
Brattle – Dominion [56]	$ 1,041
SCE&G – Workpapers[57]	$ 993

53 See 2016 EIA Report, Page 7. We applied the EIA's -10.4% location adjustment factor for South Carolina (Page A-14) and adjusted for inflation.

54 Duke completed its Dan River Combined Cycle plant in 2012. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $912, which is equivalent to approximately $1,077 in 2017 dollars.

55 Duke completed its Buck Combined Cycle plant in 2011. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $941 per KW, which is equivalent to approximately $1,060 per KW in 2017 dollars.

56 See The Brattle Group and Sargent & Lundy, Cost of New Entry Estimates for *Combustion* Turbine and Combined Cycle Plants in PJM, May 2014 ("Brattle Report"), Page 43.

57 See for example CC2023_ICT2023_0CO_BG.xlsm, tab Base PLAN, cell B12.

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBUSTION TURBINE?

A. I used an installed cost of $650 per KW in 2017. This is slightly lower than the $697 figure SCE&G used as an input in its avoided cost calculations in this proceeding. It is also lower than the $734 estimate SCE&G provided in its June 30, 2014 PURPA avoided cost filing. My decision to use the $650 figure is primarily based upon the most recent cost information published by the Energy Information Administration. However, I also considered two cost estimates provided by SCE&G, and two other publicly available data sources:

Combustion Turbine	**Cost per kW in 2017 Dollars**
Proxy Unit	**$ 650**
EIA – Advanced CT [58]	$ 645
Brattle – Dominion [59]	$ 885
Pasteris SOM – EMACC [60]	$ 763
SCE&G – 2023 CT [61]	$ 734
SCE&G – Workpapers[62]	$ 697

58 See EIA Report, Page 7. We applied the EIA's 6.8% location cost adjustment factor for South Carolina (Page A-18) and adjusted for inflation.

59 Brattle's estimate of the overnight cost of constructing an Advanced Combustion Turbine in Dominion's service area was $931 per KW in 2018/19. (Brattle Report, Page 41.)

60 See Brattle CONE CT Revenue Requirements Review, July 25, 2014, Page 12.

61 SCE&G June 30, 2014 PURPA avoided cost filing.

62 See for example CC2023_ICT2023_0CO_BG.xlsm, tab Change PLAN, cell G12.

Q. HOW DID YOU TRANSLATE THE INSTALLED COST INTO ANNUAL EQUIVALENTS?

A. First, I added an allowance for the cost of construction financing. I then developed an allowance for depreciation based on an economic life of 30 years for the combined cycle and combustion turbine units, and 70 years for the nuclear unit. These are reasonable input assumptions, which are more realistic, more conservative and more appropriate than the corresponding life estimates used in SCE&G's avoided cost analysis of 60 years for a combustion turbine, 75 years for other fossil-fueled plants, 150 years for hydro and 80 years for nuclear.[63]

I developed an estimate of income taxes using a composite state and federal tax rate of 24.95%, and I applied a weighted cost of capital of 7.18% (a pre-tax cost of capital of 8.75%), consistent with the following calculations:

Capital Source	Ratio	Cost Rate	Weighted Cost	Tax Factor	Pre-Tax Weighted Cost
Equity	50.00%	9.50%	4.75%	1.3324	6.33%
Debt	50.00%	4.85%	2.38%	1.0000	2.43%
Total	100.00%		7.18%		8.75%

63 See for example CC2023_ICT2023_0CO_BG.xlsm, tab FCR-SCEG, cells D21, F21, H21 and J21, respectively.

These capital-related ownership costs were initially developed for each individual year, then levelized across the entire economic life of the plant. The latter step is similar to the way most home mortgages are structured to provide uniform, level payments, even though the cost of the mortgage (the interest) varies from year to year. The end result was a uniform levelized capital cost of $451.86 per kW per year for the nuclear plant, $106.14 per kW per year for the combined cycle plant and $65.70 per kW per year for the combustion turbine.

Q. DID YOU CONSIDER ANY OTHER FIXED ANNUAL COSTS?

A. Yes. Before converting these levelized amounts into per-kWh costs, it was necessary to add an allowance for fixed O&M and corporate overhead costs. I assumed annual Fixed Operating & Maintenance expenses would be $95.00 per kW for the Nuclear plant, $10.00 per kW for the Combined Cycle Plant and $7.00 per kW for the Advanced Combustion Turbine (in 2016 dollars). The assumptions are consistent with estimates developed by the Energy Information Administration and data from various utilities, which I have reviewed in the course of my consulting work. Applying an annual inflation factor of 2% and levelizing each figure results in an annual cost per kW in 2017 of $119.64, $12.59 and $8.82, respectively.

I also applied a 95% availability factor, to compensate for forced outages and times when the unit is unavailable for energy production due to scheduled maintenance (and refueling in the case of a nuclear unit). An allowance for corporate overhead costs was also needed; I provided a 5% allowance for this category of costs. All of these costs were developed on a year-by-year basis, then uniformly spread across the economic life of the plant. The resulting levelized costs totaled $647.96 per kW for the nuclear plant, $131.23 per kW for the combined cycle plant and $82.36 per kW for the combustion turbine.

Q. HOW DO THESE AVOIDED COST ESTIMATES COMPARE TO THE COMPANY'S CURRENT QF CAPACITY RATES?

A. The current rates are 1.965 cents per kWh during the critical peak hours in the summer and 0.675 cents per kWh during the critical peak hours in the winter. Both rates are significantly lower than the long run avoided capacity costs associated with building and operating new generating plants. The exact comparison is shown in the following table:

SCE&G Proposed QF Capacity Rates vs. Benchmark Avoided Capacity Costs (price per kWh)

	Summer (Jun – Sep)		Other (Oct – May)	
	Proposed QF Rate	Avoided Cost	Proposed QF Rate	Avoided Cost
Critical-Peak	$ .01965	$ .2698	$ .00675	$ .0807

Recommendations

Q. WHAT ARE YOUR RECOMMENDATIONS FOR RESOLVING THE QF ISSUES IN THIS PROCEEDING?

A. The Commission should reject all of the proposed QF tariff changes, including the following:

- Reducing the capacity rate on the PR-2 tariff to zero;
- Reducing energy rates despite circumstances where heat rates have increased, providing stronger opportunities for avoiding high energy costs.
- Removing time-related price signals, which discourage investments in storage.
- Eliminating standard offer rates for non-solar generators larger than 100 kW.
- Basing rates on a generic solar profile, thereby removing incentives to invest in locations or technology that have the potential for achieving a better profile.
- Basing rates on a sub-optimal "Base" expansion plan that does not minimize revenue requirements.

The Company has not identified (and I am not aware of) an urgent need to update or revise the existing rates, which can continue in effect until these issues are properly addressed. I recommend that the Commission establish a process to fully consider the issues discussed in this testimony, and to encourage the Company to work collaboratively with ORS and other interested parties in an effort to reach a consensus on as many of the technical issues as possible. The goal should be to develop stronger, more precise hourly price signals, consistent with the earlier discussion in my testimony. This can be accomplished by modifying the inputs and assumptions used in the DRR analysis, to more accurately analyze and minimize the revenue requirements under each scenario.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, WHICH WAS PREFILED ON MARCH 23, 2018?

A. Yes.

Appendix A

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients have employed your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory commissions, public counsels, attorneys general, and local governments, among others. We have also worked for a wide variety of different private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alaska Public Utilities Commission

Arizona Corporation Commission

Arkansas Public Service Commission

Connecticut Department of Public Utility Control

District of Columbia Public Service Commission

Idaho Public Utilities Commission

Idaho State Tax Commission

Iowa Department of Revenue and Finance

Kansas State Corporation Commission

Maine Public Utilities Commission

Minnesota Department of Public Service

Missouri Public Service Commission

Nevada Public Service Commission

New Hampshire Public Utilities Commission

North Carolina Utilities Commission—Public Staff

Oklahoma Corporation Commission

Ontario Ministry of Culture and Communications

Staff of the Delaware Public Service Commission

Staff of the Georgia Public Service Commission

Texas Public Utilities Commission

Virginia State Corporation Commission

Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

National Association of State Utility Consumer Advocates

New Hampshire Office of Consumer Advocate

New York State Department of State – Utility Intervention Unit

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

Canada—Department of Communications

Hillsborough County Property Appraiser

Provincial Governments of Canada

Sarasota County Property Appraiser

State of Florida—Department of General Services

United States Department of Justice—Antitrust Division

Utah State Tax Commission

Regulated Firms

Alabama Power Company

Americall LDC, Inc.

BC Rail

CommuniGroup

Florida Association of Concerned Telephone Companies, Inc.

LDDS Communications, Inc.

Louisiana/Mississippi Resellers Association

Madison County Telephone Company

Montana Power Company

Mountain View Telephone Company

Nevada Power Company

Network I, Inc.

North Carolina Long Distance Association

Northern Lights Public Utility

Otter Tail Power Company

Pan-Alberta Gas, Ltd.

Resort Village Utility, Inc.

South Carolina Long Distance Association

Stanton Telephone

Teleconnect Company

Tennessee Resellers' Association

Westel Telecommunications

Yelcot Telephone Company, Inc.

Other Private Organizations

AARP

Arizona Center for Law in the Public Interest

Black United Fund of New Jersey

Clark Canyon, LLC

Clearwater Paper Company

Coalition of Boise Water Customers

Colorado Energy Advocacy Office

East Maine Medical Center

Georgia Legal Services Program

Harris Corporation

Helca Mining Company

Idaho Small Timber Companies

Independent Energy Producers of Idaho

Interstate Securities Corporation

J.R. Simplot Company

Merrill Trust Company

MICRON Semiconductor, Inc.

Native American Rights Fund

North Carolina Sustainable Energy Association

Skokomish Indian Tribe

South Carolina Solar Business Alliance

Tamarack Energy Partnership

Twin Falls Canal Company

World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. I have been actively involved in more than 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Initially I prepare reports for the internal use of the Florida Public Counsel, but in the subsequent years I've prepared reports for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 300 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and approximately 60 electric utilities. I have also worked on consulting engagements involving more than 35 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the International Association of Assessing Officers (IAAO), the Michigan State University

Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA) and North Carolina State University.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly*, February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly*, December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times*, February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth

Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.